STRATEGIC CENTER FOR NATURAL GAS AND OIL

STRATEGIC DRIVERS

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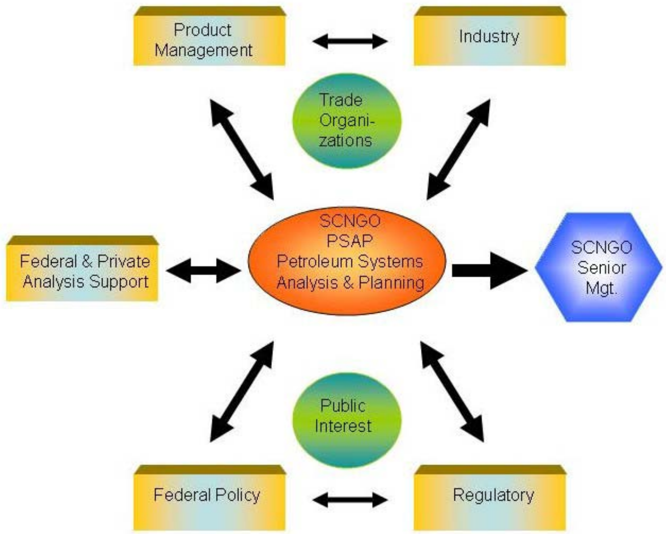
INTRODUCTION

Natural gas and oil are expected to continue to play a major role in meeting the Nation's growing demand for energy. The U.S. Department of Energy (DOE) SCNGO was established as a focal point within the Federal government to facilitate the development of policies and technologies to meet the projected demand for natural gas and oil. SCNGO serves as a portal for information on natural gas and oil—from exploration and production to transportation and delivery.

It is the role of SCNGO to work with industry to ensure that natural gas and oil technologies will be available to meet future supply needs. As part of its long-range planning, SCNGO analysts assess the impact of policies, legislation, and regulation on its major product lines. This includes assessing environmental issues, infrastructure reliability, supply accessibility and sustainability, economic trends, market practices, regulatory barriers, and other issues as they relate to SCNGO technology. One key objective is to generate timely data so that informed decisions can be made about future program direction. These analyses also provide natural gas and oil stakeholders and policy makers with thorough situational and technical assessments for their use in developing rational energy policies. Additionally, analysts provide technical data and analytical tools for program performance metrics and benefit analysis. The analysts accomplish these objectives through a host of activities, including:

- coordinating natural gas and oil policy assessments performed in-house and through contracted efforts,
- keeping abreast of policy-related issues,
- anticipating industry trends and proposed regulations that could impact NETL's suite of natural gas and oil products,
- assimilating these data to provide senior management with the information needed to make informed decisions about the direction and budget of the natural gas and oil program,
- interacting with industry and policy makers to continue or enhance the dialogue on natural gas and oil issues, and
- formulating methods to measure and track performance measures and estimate future benefits of SCNGO's technologies as a function of total and incremental funding.

The SCNGO analysts have extensive experience in energy production, use, and research. Drawing on this expertise, the analysts' strategy includes fostering relationships with industry organizations, other federal agencies, regulatory agencies, and consumer groups (Figure 1). Through these relationships, the analysts stay abreast of the most pressing natural gas and oil issues, regulations, and policy initiatives. At the same time, this network enables the analysts to disseminate useful information and analyses, and to be included in discussions with key stakeholders when policy matters are on the table. The analysts work closely with project managers, NETL's in-house R&D organization, and with DOE headquarters personnel to sponsor studies and to understand technical developments pertaining to natural gas and oil production and supply. The analysts also play an integral part in the technology areas within the SCNGO by assisting product



managers in strategic planning for their products. And last, the analysts maintain a dialogue with senior management to anticipate the type of assessments and information that will be needed to make critical program decisions.

Figure 1: Function of the SCNGO Analysts

The SCNGO analysts have developed the following goals for fiscal year (FY) 2004:

1. Generate timely data on policy-related issues, industry trends, and proposed regulations that could impact NETL's suite of natural gas and oil products.
2. Conduct analyses that anticipate and support U.S. gas and oil policy developments as they relate to SCNGO technologies.
3. Conduct integrated outreach and communications activities for DOE's gas and oil programs and policy positions.
4. Support development of metrics and assessment of program benefits.
5. Conduct inter-agency policy evaluations on matters of national importance.

The nation faces a number of challenges to provide long-term sustainable and affordable natural gas and oil supplies. The government has a role to ensure that technology and policy come together and provide the proper framework that will ensure a balanced energy future; one that provides secure energy, protects the environment and stimulates the engines of this nation's economic growth. For oil and gas, the SCNGO analysts facilitate this government role through comprehensive and accurate, unbiased planning so that NETL's natural gas and oil programs are properly integrated into the overall energy strategy.

In summary, this document provides a strategy or framework in which SCNGO analysts conduct business. The document provides an analysis of some of the major challenges facing this Nation with respect to oil and gas exploration, production and delivery. The document also addresses key stakeholder concerns. Finally, the document provides a multi-year summary of key goals and objectives that will be pursued by SCNGO analysts to help advance oil and gas technology, and promote a balanced energy future.

NATURAL GAS - SITUATION ANALYSIS

Natural gas provides roughly a quarter of the energy consumed in the U.S. (on a Btu basis) and the Energy Information Administration (EIA) projects steady growth in natural gas consumption though 2025. Demand for natural gas is expected to grow in all sectors of the economy, with the greatest growth forecasted for the electric power sector. Future expansion of electric generation capacity is expected to be powered by natural gas because of the many advantages natural-gas-fired generators provide. Overall, consumption in natural gas is expected to rise almost 40 percent to 31.4 trillion cubic feet (Tcf) by 2025 compared to the 22.8 Tcf consumed during 2002.

Most experts agree that domestic production from conventional gas resources cannot keep pace with the projected growth in U.S. demand. Natural gas from Alaska and increased production of unconventional gas, predominantly from the Rocky Mountain region, may provide some supply relief, but not at sufficient levels to balance supply with expected demand. Furthermore, pipeline transportation of North Slope gas is not expected to come online until 2018. Experts agree that the supply and demand imbalance will be met through increased net imports of natural gas. Today, about 15 percent of the gas consumed in this country comes from our neighbors to the north. Unfortunately, Canada is facing similar challenges as the U.S. Rising national demand for natural gas and lower production from conventional resources, is expected to curtail Canadian exports to the U.S. beginning in 2010.

Because natural gas is such an integral part of this country's fuel mix, our domestic natural gas supply, the reliability of delivery, and the need for affordable and stable prices are each crucial to our economy. In an effort to establish a coordinated, long-term energy policy, the Bush Administration issued its National Energy Policy (NEP) report in May 2001 that outlines a variety of recommendations for securing our energy future. The NEP calls for promoting enhanced recovery of domestic natural gas (and oil) through advanced technologies, economic incentives and new policies that ensure energy security, maintain reasonable energy prices, and protect the environment.

A backdrop to energy policymaking has been the volatility of natural gas prices over the past three years. The source of this volatility has been the combination of steady demand, domestic production capacity limitations, unusual weather patterns during both winter heating and summer cooling seasons, local bottlenecks and supply disruptions in an over-taxed gas pipeline infrastructure and, in some cases, regulatory missteps. During the winter of 2000-2001, spot gas prices reached record highs of over $9 per thousand cubic feet (Mcf), the result primarily of a constrained domestic production capacity coupled with high demand. Spot prices then dropped over 80 percent to the $2 to $3/Mcf range during 2001. Following a period of steady increase during 2002 to the $4/Mcf range, spot prices rose again during the winter of 2002-2003, spiking as high as $15/Mcf before returning to the $4-$5/Mcf range during 2003. Price volatility has a major impact in the economic decision making of industrial consumers, power generators and homeowners.

Key NPC Recommendations

- Continue DOE research into natural gas supply, transportation and end use technologies, particularly where it complements privately funded efforts.
- Enact enabling legislation for the Alaskan gas pipeline by providing regulatory certainty in 2003 (the state of Alaska should provide for fiscal certainty to project sponsors by 2004).
- Overcome local siting opposition to new LNG terminals through public education and continuous industry reviews, and streamline the LNG terminal permitting process by coordinating agency activities.
- Streamline the permitting processes to allow for increased drilling and development activity in the Rocky Mountains.
- Remove moratoria on selected areas of the Federal outer continental shelf (OCS) by 2005 and ensure continued access to OCS areas identified in the 2002-2007 5-year leasing program.
- Implement a Joint Agency Review process for new pipeline infrastructure projects, with priority for projects that connect incremental supply and eliminate market imbalances.

An indication of the administration's level of concern regarding natural gas was the request by Secretary of Energy Spencer Abraham that the National Petroleum Council (NPC) update their 1992 and 1999 reports on natural gas markets. This new study, released in September 2003, examines the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions on natural gas demand, supply, and delivery through 2025. The report provides more than 50 specific recommendations (see sidebar) regarding actions that the Federal government can take to improve the productivity and efficiency of North American natural gas markets and ensure adequate and reliable supplies of energy for consumers.

During the summer of 2003, natural gas became one of the hottest issues on Capital Hill. A number of task forces were established to look into the potential "pending crisis." Federal Reserve Chairman Alan Greenspan speaking to the House Energy and Commerce Committee on June 10 highlighted the gap between North American gas demand and available supply. With 95 percent of the gas reserves located outside the continent and the U.S. alone accounting for over a quarter of the global consumption, Greenspan painted a grim picture of the potential affects of rising gas prices on American consumers. He went on to recommend that the U.S. build more liquefied natural gas (LNG) terminals to import natural gas. In response, Secretary Abraham hosted the LNG Ministerial Summit December 17-18, 2003), which brought together energy ministers from 24 countries to take a fresh look at the world LNG market place. The Summit served as a forum to explore global natural gas resources and growing markets, new and emerging technology, security, regulatory and siting challenges, opportunities and barriers for investment in the LNG industry. The LNG Ministerial Summit also provided a forum for private sector to share information on the future of the LNG economy and to discuss relevant public policy issues.

Oil - Situation Analysis

Consuming nearly 20 million barrels per day (mbpd), Americans rely heavily on oil to meet their energy needs; nearly 40 percent on a Btu basis. Approximately 53 percent of the oil demand is met through imports of crude oil and refined petroleum products such as gasoline and diesel fuel for the transportation sector, which alone consumes 67 percent of total U.S. petroleum consumption. According to the EIA Annual Energy Outlook 2004 *(AEO2004)* by 2025, petroleum consumption is expected to increase to over 28 mbpd maintaining a 40 percent share of total U.S. energy consumption. Unfortunately, during this same time period, crude oil and petroleum product imports are projected to rise significantly accounting for 70 percent of total U.S. petroleum consumption.

The U.S. is the most mature oil-producing region in the world, and has experienced a steady drop in production since the 1970s. In recent years this decline has been buffered somewhat by increases in offshore production, but *AEO2004* forecasts predict that production offshore will peak in 2008 and then steadily decline. Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs (e.g., deep water and harsh environments).

NEP Recommendations – Stemming the downward spiral of domestic oil production

- Promote enhanced oil recovery from existing wells through new technology - 30 to 70% of oil is not recovered; EOR could add 60 Bbl of oil.
- Reduce impediments to federal onshore and offshore land leasing – with advanced technology, 59 Bbl could be recovered from the OCS (4.1 Bbl onshore).
- Improve oil and gas exploration technology through continued partnership with public and private entities.
- Consider economic incentives for environmentally sound offshore oil (and gas) development including royalty reductions for enhanced oil and gas recovery; production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.
- Expand environmentally responsible development, based on best available technology in the NPR-A (2.1 Bbl).
- Authorize environmentally responsible exploration and development, based on best available technology of the ANWR (10.4 Bbl).

Experts acknowledge that preventing the decline in domestic oil production is unlikely, but a number of options exist to curtail the rate of decline and offset the need for increased imports. NEP recommendations (see sidebar) seek to 1) enhance production from existing wells through advanced technology, 2) provide economic incentives for increased production from unrestricted frontier areas and 2) remove barriers for access to and exploration and production on currently restricted federal lands.

Without the measured describes above, America will become increasingly reliant on foreign petroleum and refined products. As has been witnessed over the past year, dependency on foreign oil can have significant consequences on our economy; most noticeably the price consumers pay at the pump. Factors including seasonal demand and storage inventory affect refined product prices, but it's the price of crude oil that has the greatest impact (~ 40% of the cost of gasoline). Crude oil prices are determined by worldwide supply and demand, with significant influence by the Organization of Petroleum Exporting Countries (OPEC). Since it was organized in 1960, OPEC has tried to keep world oil prices at its target level ($22 - $28) by setting an upper production limit on its members. OPEC has the potential to influence oil prices worldwide because its members possess such a great portion of the world's oil supply, accounting for almost 40 percent of the world's production of crude oil and holding more than two-thirds of the world's estimated crude oil reserves. At a meeting in February 2004, OPEC decided to reduce its production ceiling beginning April 1st by one million barrels per day, from 24.5 to 23.5 mbpd. Because of the weaker dollar, OPEC is considering raising the target price band. While individual OPEC member countries have often exceeded their production quota causing downward pressure on worldwide crude oil prices, U.S. retail gasoline prices have already risen and are expected to climb throughout the 2004 summer driving season.

POLICY DRIVERS

Clearly, *policies are needed to ensure that oil and gas production in the U.S. is maximized while also preserving the environment, and that stable and secure energy sources—foreign and domestic—are established in order to meet the nation's energy needs.* The SCNGO plays a vital role in promoting advanced technologies within the framework of sound energy policy. The primary drivers for developing domestic natural gas and oil policies are the need for: (1) energy security, (2) environmental protection and (3) long-term affordable energy (Figure 2).

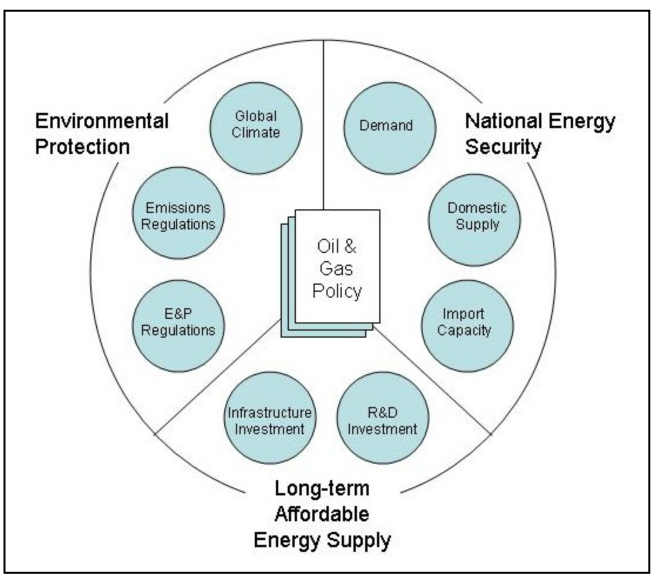


Figure 2: Key Components of Energy Policy Drivers

The key issues behind these drivers are discussed below in the context of how they may have an impact on the natural gas and oil industry and influence technology R&D. Many, indeed most, of these issues are interrelated … supply is affected by environmental regulations and new technology investments… demand is influenced by emissions regulations … import capacity is affected by infrastructure investments. The challenge for policymakers is achieving a balanced portfolio of policies that together further national goals.

National Energy Security

There are three key components to this driver: demand growth, domestic supply and import capacity.

Natural Gas Demand Driven by Power Generation Needs. According to the *AEO2004*, total natural gas consumption is projected to increase over the next two decades, regardless of the economic growth scenario chosen. The projections for domestic natural gas consumption in 2025 range from 29.1 trillion cubic feet (Tcf) per year in the low economic growth case to 34.2 Tcf in the rapid technology case. In the reference case, natural gas consumption is expected to increase nearly 40 percent by 2025 to 31.4 Tcf, as compared with 22.8 Tcf in 2002.

Demand for natural gas is expected to grow in all sectors of the economy. Industry will continue to consume the largest share of natural gas. In the reference case, industrial consumption is projected to increase from 7.2 Tcf in 2002 to 10.3 Tcf, accounting for 33 percent of total end-use natural gas consumption in 2025. The greatest growth in gas consumption, however, is driven by electric power generators. In the reference case, natural gas consumption for electricity generation increases from 5.6 Tcf in 2002 to 8.4 Tcf in 2025, an average annual growth rate of 1.8 percent (Figure 3).

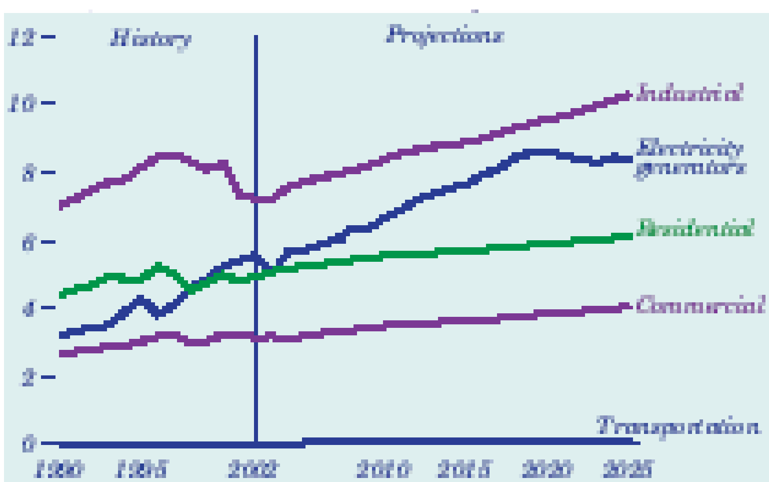
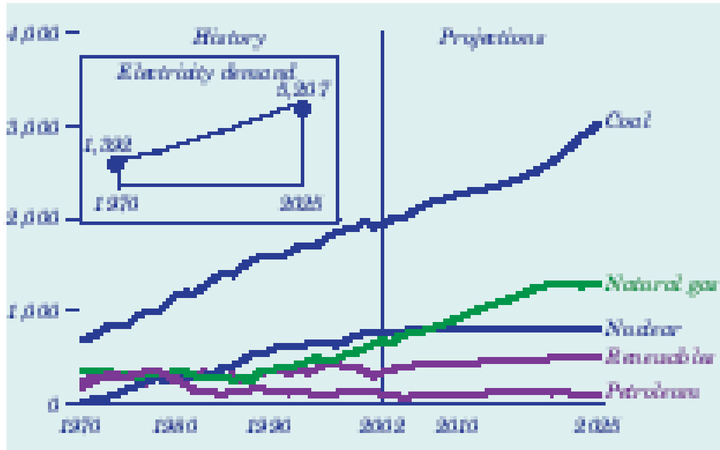


Figure 3: Projected Natural Gas Consumption
(EIA AEO2004, Fig. 85)

This demand growth is driven by the advantages natural-gas-fired generators have over coal-fired generators, including lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions. Natural gas generated electric power is projected to increase from 13 percent of total electric power in 2002 to 18 percent in 2025 (Figure 4). Previous EIA forecasts predicted even greater growth in gas-generated electricity; as much as 25 percent of all electricity generated in 2025. These estimates have been revised downward due to higher projected gas prices in the most recent forecast. As shown in Figure 5, after 2020 higher gas prices (relative to coal) result in new additions and greater utilization of goal-fired capacity.

Figure 4: Projected Electricity Generation by Fuel
(EIA AEO2004, Fig. 4)



Oil Demand Driven by Transportation Sector. U.S. petroleum consumption is projected to increase by 8.7 mbpd to 28.3 mbpd between 2002 and 2025. Most of the increase (7.1 mbpd) is in the transportation sector (Figure 5). Motor gasoline will continue to account for about 47 percent of all petroleum used in the U.S. throughout the forecast period. From 2002 to 2025, U.S. gasoline consumption is projected to rise from 8.9 mbpd to 13.3 mbpd; an annual growth rate of 1.8 percent. The greatest growth is in the consumption of distillate fuel. With an annual growth rate of 1.9 percent distillate fuel is projected to be 2.0 mbpd higher in 2025 than it was in 2002. This increase is driven by increased demand for diesel fuel in the transportation sector. Petroleum consumption in the industrial sector, which currently accounts for 24 percent of U.S. petroleum use, is expected to grow by 1.4 mbpd.

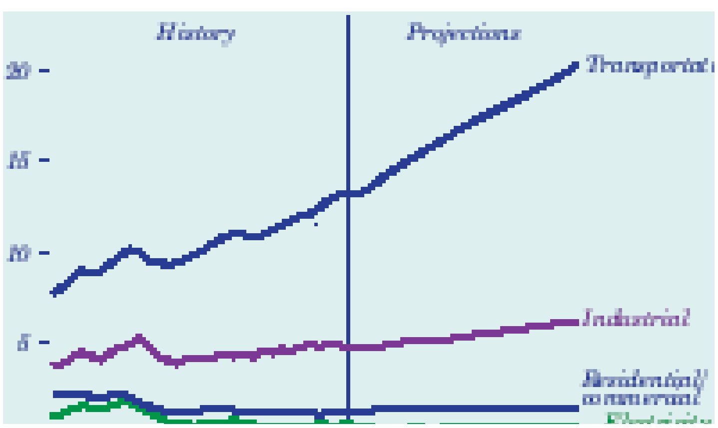


Figure 5: Petroleum Consumption by Sector
(EIA AEO2004, Fig. 102)

Gas Production Driven by Rocky Mountain Unconventional Resources. The *AEO2004* projects that greater levels of exploratory and developmental drilling resulting from higher gas prices and production revenues, will lead to an increase in addition to reserves by the lower 48 states. In the reference case, lower 48 reserve additions are expected to peak in 2018 and then slowly decline to 2025 (Figure 6). Accelerating the development and use of advanced technology has the affect of shifting peak reserve additions to 2023 by improving success rates and lower the cost of exploration and production.

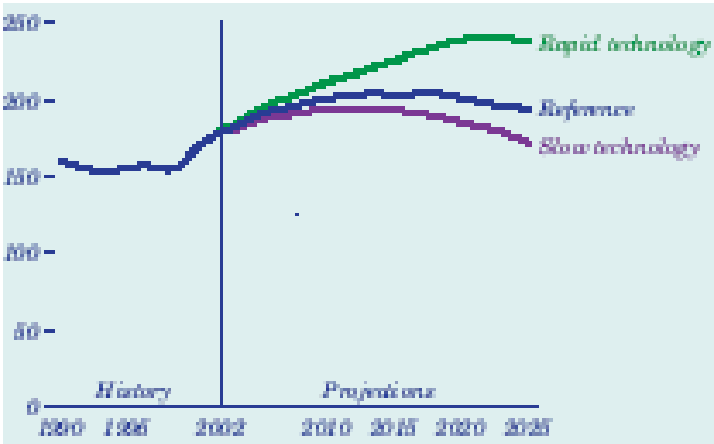
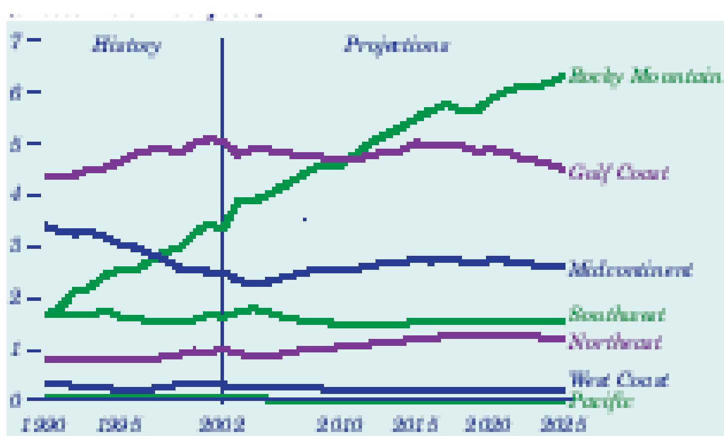


Figure 6: Projected Domestic Reserves Additions
(EIA AEO2004, Fig. 92)

Technological improvements also make it possible for industry to more effectively produce natural gas from unconventional resources (tight sands, shale, and coal seams). In the reference case, lower 48 unconventional gas production is projected to grow from 5.9 Tcf in 2002 to 9.2 Tcf in 2025, increasing from 31 percent to 38 percent of total U.S. production. Total domestic natural gas production is expected to increase by 4.9 Tcf over the forecast period (2002 to 2025) thus; production from unconventional resources contributes nearly 70 percent to this increase. The vast majority of this increase is projected to come from unconventional gas resources in the Rocky Mountain region (Figure 7). In the reference case, Rocky Mountain gas production is forecasted to increase from 3.3 Tcf in 2002 to 4.6 Tcf in 2010 and 6.3 Tcf in 2025.

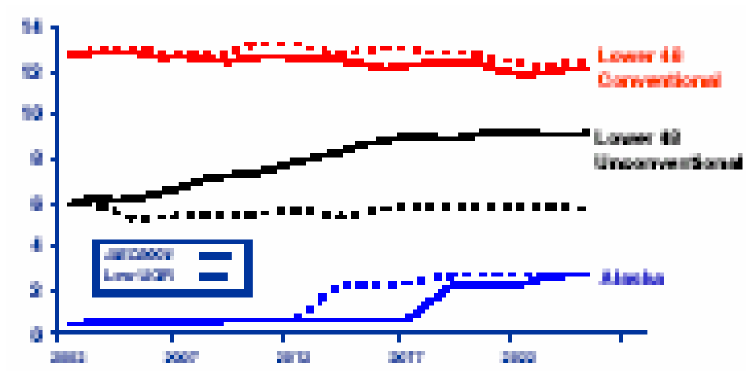
Figure 7: Rocky Mountain Region Unconventional Gas Key to Production Growth
(EIA AEO2004, Fig. 88)



EIA has recently published an *Analysis of Restricted Natural Gas Supply Cases*[1] that includes a forecast scenario based on restricted unconventional gas recovery. This scenario assumes no technical advances and lower per well production. The affect of these assumption on domestic gas production are shown in comparison to reference case production projections in Figure 8.

[1] Energy Information Administration, *Analysis of Restricted Natural Gas Supply Cases,* February 2004.

Figure 8: Unconventional Gas Production Sensitive to Advancement of Technology *(EIA Restricted Supply, Fig. 13)*



Under this scenario, unconventional gas production is expected to remain relatively flat falling by only about 0.5 Tcf per year below the 2002 level by 2025. This amounts to about a 3.5 Tcf loss in 2025 compared to the reference case. The loss in lower 48 gas supply causes wellhead gas prices to be higher throughout the forecast, which in turn accelerates construction of an Alaska gas pipeline to the lower 48 with operations beginning in 2013; five years earlier than in the reference case. Completion of a pipeline to transport gas from the North Slope to the lower 48 States is expected to bring online gas reserves estimated at 35 Tcf. Another 16 Tcf is expected to be found and developed thus, a total resource base of 51 Tcf could be available to support the Alaskan gas pipeline. By 2025, total Alaskan gas production is projected to be 2.7 Tcf in the *AEO2004* reference case. EIA's restricted gas supply analysis investigates a "No Alaskan Pipeline" scenario. In this case, U.S. supply is met by greater levels of imported gas and slight increases in lower 48 production.

Other production regions, both onshore and offshore, will collectively provide some increase in gas production over the forecasted period. For example, increased drilling activity in deep waters is expected to expand offshore natural gas production slightly; however its overall share of total U.S. production is expected to decline from 26 percent in 2002 to 21 percent by 2025.

Domestic Oil Production Continues to Decline. Over the forecast period (2002 - 2025), domestic oil production is expected to decline 1.0 mbpd from 2002 levels of 5.6 mbpd. This decline is dampened somewhat by increased production from lower 48 offshore fields, which rise from 1.5 mbpd in 2002 to a peak of 2.5 mbpd in 2008 and then decline to 2.1 mbpd in 2025 (Figure 9). The near-term increase in offshore production is driven by deep oil wells.

Offshore crude oil production is more sensitive to changes in technology than onshore production. Consequently, in the *AEO2004* rapid technology case, investments shift to offshore resulting in an increase in cumulative production from 2002 to 2025 of 1.2 billion barrels (6.3 percent increase), whereas onshore production falls about 0.3. In the slow technology case, onshore production increases 0.3 percent and offshore production drops by a cumulative amount of 1.0 billion barrels (5.4 percent) between 2002 and 2025.

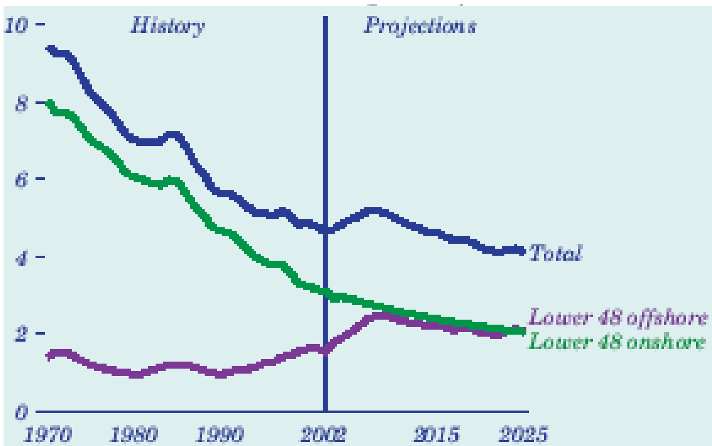
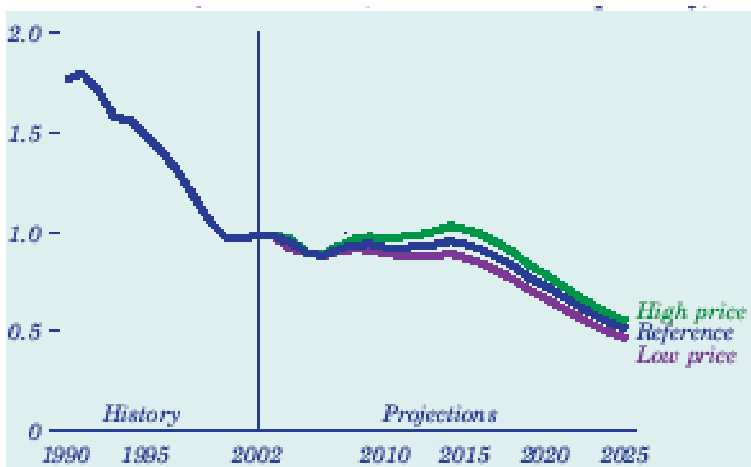


Figure 9: Domestic Crude Oil Production
(EIA AEO2004, Fig. 96 & Table 25)

	2002	2010	2015	2020	2025
Shallow	0.6	0.7	0.6	0.7	0.5
Deep	0.8	1.6	1.6	1.3	1.5
Total	1.4	2.4	2.2	2.0	2.0

In the *AEO2004* reference case, crude oil production from Alaska is expected to continue at about 900 thousand barrels per day through 2016 (Figure 10), with a projected drop in North Slope oil production offset by new oil production from the National Petroleum Reserve-Alaska (NPR-A). After 2016, total Alaskan crude oil production is projected to decline, to 510 thousand barrels per day in 2025. As in the lower 48 States, oil production in Alaska is projected to be sensitive to changes in oil prices. Higher prices make more of the oil in-place profitable, particularly in the North Slope heavy oil fields.

Figure 10: Alaskan Crude Oil Production
(EIA AEO2004, Fig. 98)



Because drilling is currently prohibited in the Arctic National Wildlife Refuge (ANWR), the *AEO2004* does not forecast any production from ANWR. Should access to ANWR be approved, the National Defense Council Foundation estimates[2] that in the first 15 years over 16 Bbl of oil could be produced with peak production near 1.6 mbpd. If these rates of production were achieved, ANWR could potentially supply between 5 to 10 percent of the nation's daily petroleum needs. In recent testimony to U.S. House of Representative lawmakers, EIA officials claim that opening the 1002 area of ANWR could mean that the U.S. imports 8 percent less crude oil in 2025.[3]

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[2] Based on USGS estimates of economically recoverable reserves.
[3] *EIA: Leasing ANWR's 1002 area spells less oil imports*, Oil and Gas Journal, April 5, 2004.

Technological improvements over the past 40 years have dramatically reduced industry's footprint on the tundra, minimized waste produced, and protected the land for resident and migratory wildlife. These advances include the use of ice roads and drilling pads, low-impact exploration approaches such as winter-only exploration activities, and extended reach and throughtubing rotary drilling. These technologies have significantly reduced the size of production-related facilities on the North Slope. Estimates indicate that no more than 2,000 acres will be disturbed if the 1002 Area of ANWR is developed.

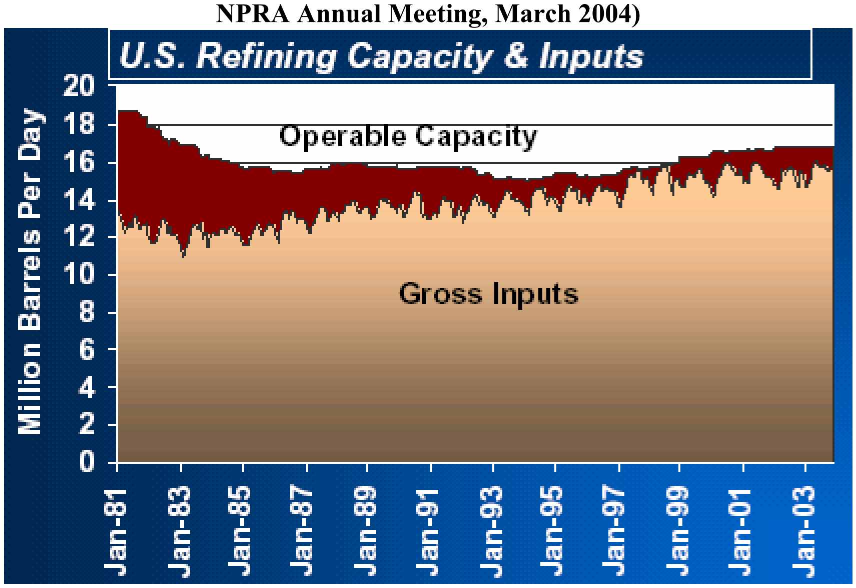
Another domestic resource not captured in the *AEO2004* forecast is the large deposits of oil shale. Estimates of the shale oil potential of the U.S. oil shale resource exceed 1 trillion barrels. Much of this potential could be produced with existing technology. The production of oil from Canada's tar sand deposits now approach 1 mbpd and serves as a model for development of the U.S. oil shale resource.

U.S. Refinery Capacity; Another Piece of the Domestic Oil Supply Puzzle. Unlike natural gas, which requires minimal processing, primarily for the removal of impurities and water, crude oil must be processed to produce marketable finished products. Approximately 56 percent of crude oil processed in the U.S. is converted to motor gasoline. Distillate oil (e.g., fuel oil for heating homes and diesel fuel for transportation) accounts for about 24 percent of the domestically produced refined products, with jet fuel, residual oil and other minor products making up the remainder.

U.S. refineries, already operating at greater than 90 percent of capacity on average (Figure 11), will be hard pressed in the future to meet growing demand for gasoline and other transportation fuel. The *AEO2004* does project distillation capacity to increase from 16.8 mbpd to 21.8 mbpd in 2025. Almost all the capacity expansion is projected to occur at existing facilities on the Gulf Coast and utilization rates are expected to continue in the range of 91 to 95 percent of operable capacity throughout the forecast. Domestic refineries are also likely to expand additional "downstream" processing units to allow production to meet a growing slate of higher value "light products," such as gasoline, distillate, jet fuel, and liquefied petroleum.

Future investment in refining capacity to meet the increased demand for high value products will include the need to produce products with more stringent specifications, driven by regional and national air quality concerns. An additional burden will be the need to supply lighter products from crude oils whose quality is expected to deteriorate over the forecast period. These factors will put additional pressure on U.S. refineries in the future with the result likely to be ever growing import of finished products.

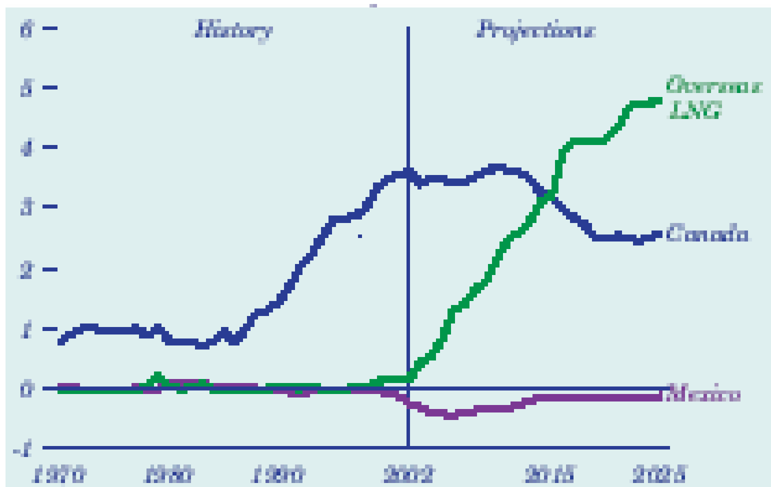
Figure 11: U.S. Refining Capacity & Inputs
(EIA, Challenging Times for Making Refinery Capacity Decisions
NPRA Annual Meeting, March 2004)



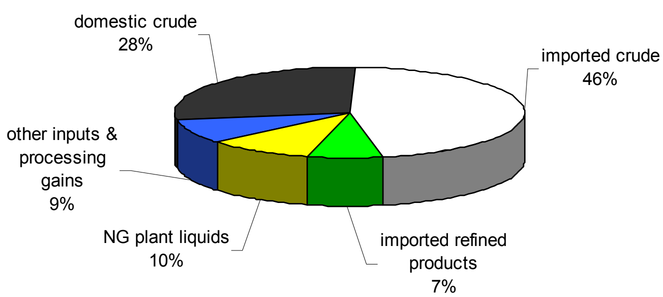
Imports Fill the Gap Between Supply and Demand. Increased production in the lower 48 and Alaska will not be sufficient to satisfy the expected increase in U.S. natural gas demand. Net imports of natural gas will need to make up the gap between U.S. production and consumption. Past forecasts projected that imports from Canada would continue to provide approximately 15 percent of the U.S. supply. The depletion of conventional resources in the Western Sedimentary Basin and two recent drilling disappointments (Ladyfern field in British Columbia and the Scotian Shelf Deep Panuke field) have resulted in downward revisions of future production estimates by the Canadian National Energy Board. Canadian imports are now expected to remain relatively flat at about 3.5 Tcf until 2010 and then gradually decline to 2.6 Tcf or 8 percent of total U.S. supply in 2025.

To offset the decline of Canadian imports and meet growth in U.S. gas demand, experts now believe that expansion of liquefied natural gas (LNG) imports will be necessary. Currently, LNG makes up about 2.5 percent (~0.5 Tcf) of U.S. gas supply. With the expansion of the existing four LNG import terminals and the addition of new facilities, LNG imports are expected to grow to 4.8 Tcf by 2025 or 15 percent of U.S. natural gas supply (Figure 12). In the *AEO2004* reference case forecast, four new LNG terminals are expected to open on the Atlantic and Gulf Coasts between 2007 and 2010, with additional capacity added in the Baja California and other regions in later years. The restricted gas supply analysis provides a constrained LNG scenario where capacity is constrained to 2.5 Bcf per day through 2025. This restricted case results in higher wellhead gas prices, greater imports from Canada and Mexico and increased domestic production. As of March 2004, fourteen new terminals have been approved or are pending approval from FERC or the U.S. Coast Guard. The combined sendout capacity of these new LNG facilities is over 16 Bcf per day. The three approved facilities have a combined capacity of 2.5 Bcf per day and expected to come online by 2007.

Figure 12: LNG Imports Rise to Offset Demand/Production Imbalance
(EIA AEO2004, Fig. 89)



In 2002, U.S. primary petroleum supply was 19.8 mbpd comprised of domestic and imported crude oil as well as imports of refined petroleum products. Imported petroleum and refined products currently account for 53 percent of total U.S. petroleum consumption (Figure 13). Since 1990, refined product imports have more than doubled. As a result, imports have become an essential source of supply, particularly in the U.S. East Coast, where they meet about 24 percent of the gasoline demand.



OPEC, with its vast store of readily accessible oil reserves, provides almost 40 percent of the world's petroleum. About 68 percent (~21 mbpd) of the OPEC supply comes from countries in the Persian Gulf. The U.S. gets about 44 percent of its imported oil from OPEC. Half of this or 22 percent of all petroleum imports to the U.S. come from the Persian Gulf. The International Energy Outlook 2003 (*IEO2003*) projects that 61 percent of the increase in petroleum demand over the next two decades will be met by production from members of OPEC rather than non-OPEC suppliers (Figure 14). With large proved reserves and relatively low costs for expansion, OPEC members should be able to accommodate sizable increases in petroleum demand. The projected increase in OPEC production capacity in the *IEO2003* reference case is consistent with announced plans for OPEC capacity expansion. By 2025, OPEC production is projected to be about 56 mbpd, an increase of 83 percent above current levels. The growth and diversity in non-OPEC oil supply have shown surprising resilience even during the low price environment of the late 1990s. Although OPEC producers will certainly benefit from the projected growth in oil demand, significant competition is expected from non-OPEC suppliers. The *IEO2003* reference case projects an increase of 35 percent (~16 mbpd) in non-OPEC production by 2025.

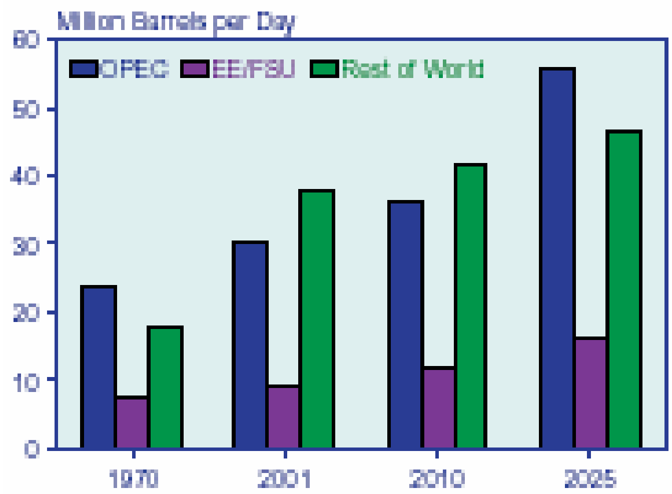
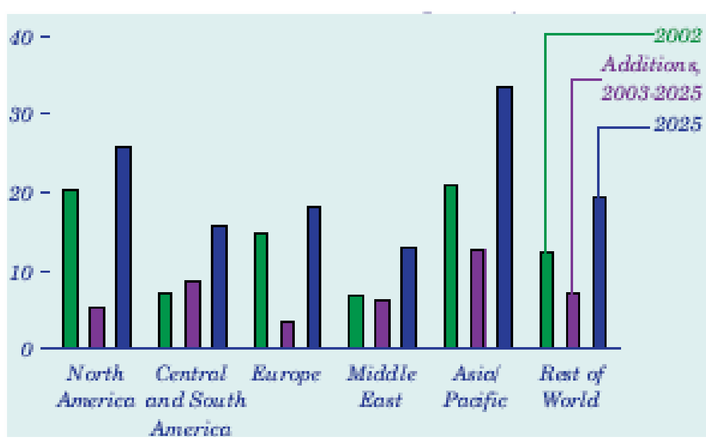


Figure 14: World Oil Production (*EIA IEO2003, Fig. 37*)

Countries expected to register production increases over the next decade include Australia, Canada, and Mexico. Canada is expected to almost double current production volumes by significantly increasing unconventional output from oil sands in its western territory. In Latin America, Brazil, Argentina, Ecuador, Peru, and Trinidad are showing accelerated growth in oil production, due in part to privatization efforts. Deepwater projects off the coast of western Africa and in the South China Sea will start producing significant volumes of oil early in this decade. In addition, much of the increase in non-OPEC supply over the next decade is expected to come from the former Soviet Union, and political uncertainty appears to be the main potential barrier to the development of vast oil resources in the Caspian Basin.

To meet the growth in international oil demand, worldwide refining capacity is expected to increase by about 53 percent—to more than 125 million barrels per day—by 2025. Substantial growth in distillation capacity is expected in the Middle East, Central and South America, and the Asia/Pacific region (Figure 15). The Asia/Pacific region has been the fastest growing refining center over the past decade. In the mid-1990s, it surpassed Western Europe as the world's second largest refining center (after North America) in terms of distillation capacity; and in 2002, this region surpassed even North America.

Figure 15: World Refining Capacity (*EIA AEO2004, Fig. 101*)



With projected declines in domestic oil production and corresponding increases in demand for refined products, more and more of America's needs will be met by foreign supply. The *AEO2004* estimates that by 2025 imported foreign petroleum and refined petroleum products combined will grow, meeting 70 percent of the nation's needs.

Clearly, imported oil and gas represents a large and growing portion of the nation's energy portfolio. As competition for the world's fossil energy supplies due to economic expansion in other areas of the world, our nation's future energy security will require sound energy policy that provides broad portfolio of secure and stable sources of supply.

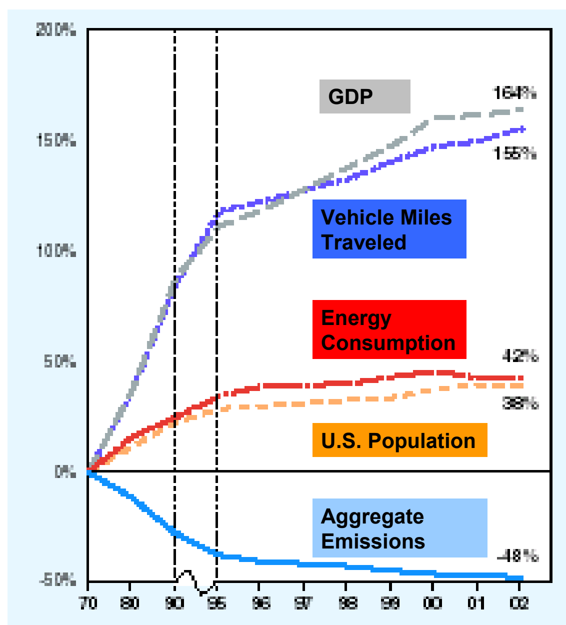
Environmental Protection

There are three key components to this driver: more stringent air emissions regulations and global climate change, drilling and production waste including produced water, and environmentally driven restrictions on exploration and production (E&P) access to Federal lands, particularly in the Rocky Mountains and offshore.

Air Emissions and Global Climate Change. The 1990 Clean Air Act Amendment (CAAA) requires a phased reduction in annual emissions of sulfur dioxide by electricity generators, and caps these emissions at 8.95 million tons per year in 2010. Many electric utilities affected by the CAAA have elected to replace high-sulfur coal with other fuels such as natural gas to meet these requirements. As a result, aggregate emissions have been significantly reduced (Figure 16). Because utility companies can bank allowances for future use, forecasts predict that the 8.95 million tons per year cap will not be met until 2014. The Administration's Clear Skies Initiative, announced in early 2002, calls for power plants to further cut emissions of three air pollutants—sulfur dioxide, nitrogen oxides, and mercury—70 percent by 2018. This adds further incentive for power plants to switch to burning environmentally friendly natural gas.

Figure 16: Comparison of Growth Areas and Emissions
(EPA: Latest Findings on National Air Quality: 2002 Status and Trends, August 2003)

	Percent Change in Air Quality 1983-2002	1993-2002
NO_2	-21	-11
O_3 1-h	-22	-2[4]
8-h	-14	+4[4]
SO_2	-54	-39
PM_{10}	—	-13
$PM_{2.5}$	—	-8[b]
CO	-65	-42
Pb	-94	-57



Approximately 85 percent of U.S. greenhouse gas (e.g., carbon dioxide, nitrous oxide and methane) emissions are energy related. Growing concern regarding increased greenhouse gas emissions and resulting changes in the Earth's climate prompted the announcement of the Administration's Global Climate Change Initiative in February 2002. A key goal of this initiative is to reduce U.S. greenhouse gas intensity (the ratio of total greenhouse gas emissions to economic output) by 18 percent by 2012. To achieve this goal, electric generators are being asked to voluntarily reduce emissions of these gases. Again, this Initiative adds further incentive for power plants to switch to from burning traditional fossil fuels to burning clean natural gas.

According to the *AEO2004* reference case, greenhouse gas intensity is expected to decline by 14 percent between 2002 and 2012. To reach the Administration's goal of reducing greenhouse gas intensity by 18 percent by 2012 would require additional emissions reductions of about 394 million metric tons carbon dioxide equivalent. Although the *AEO2004* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case results in 175 million metric tons less carbon dioxide emissions in 2012 than in the reference case. As a result, U.S. greenhouse gas intensity would fall by almost 16 percent over the 2002-2012 period, still somewhat short of the Administration's goal (Figure 17).

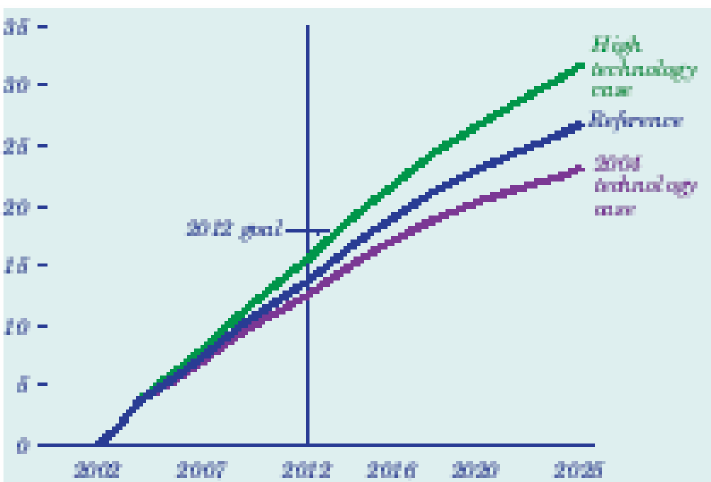


Figure 17: Greenhouse Gas Intensity
(EIA AEO2004, Fig. 37)

As noted, many air quality and emissions regulations are driving the increased demand for natural gas. However, as demand for gas (and oil) increases so do air emissions resulting directly from a variety of production, transportation and processing sources. A large portion of these emissions are fugitive emissions resulting from leaks in valves, pumps, tanks, pipes, etc. While individual leaks may be small, the sum of all fugitive leaks contributes to regional and local air quality. Production of oil and gas itself requires the use of machinery including pumps, heater-treaters, and motors which require fuel combustion. These processes generate emissions that may contain relatively high levels of carbon monoxide, sulfur and nitrogen oxides, particulates and VOCs.

Production Wastes and Produced Water. Exploration and production activities produce a substantial volume of byproducts and wastes that must be managed. The largest volume byproduct by far is produced water. As producing wells age the volume of water increases. Those nearing the end of their productive lives can produce as much as 98 percent water. The American Petroleum Institute estimates that over 15 billion barrels of water are produced annually (from both oil and gas production). Natural gas wells typically produce much lower volumes of water than oil wells however, there are important exceptions. The production of coalbed methane and often gas from tight-gas formations result in large quantities water. Unless economic and publicly acceptable solutions are found in the near future, the problem of produced water threatens many key emerging plays. This is especially true in the Rocky Mountain region which produces a large and potentially growing portion of the domestic gas supply.

Unwanted water production in otherwise promising formations reduces recovery and adds cost for disposal. These large volumes of water have the potential to impact surface water and near surface ground water. While most—more than 90 percent of onshore produced water—is re-injected into the ground, careful management is necessary to minimize environmental impacts. Opportunities exist, especially in the western U.S. where water is often a scarce resource, to treat the water (if necessary) and use it for beneficial reuse applications such as irrigation and livestock watering. Most often, produced water meets federal clean water and drinking water standards. However, in some cases the water contains high levels of sodium making it unsuitable for irrigation and so it must be treated. Beneficial use of produced water currently accounts for about 5 percent of the onshore produced water.

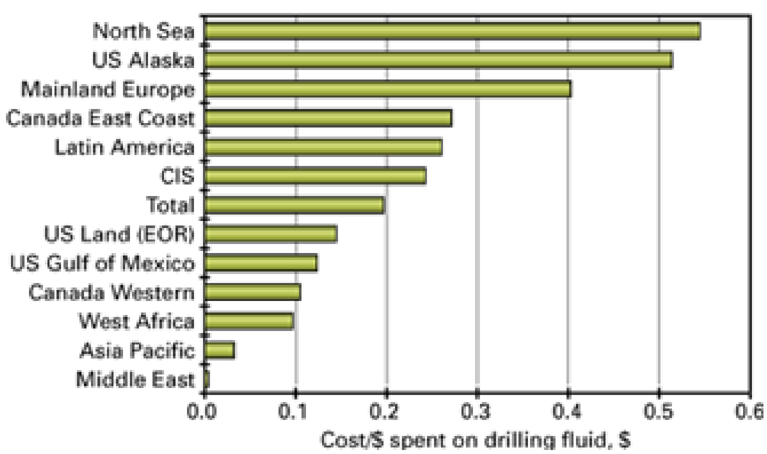


Figure 18: Drilling Waste Costs *(O&G Journal August 11, 2003)*

In addition to produced water, the oil and natural gas extraction process results in outputs of drilling mud, drill cuttings, and well maintenance products. Disposal of these materials have the potential to create environmental impacts if not carefully managed. A recent survey of drilling companies conducted by the Oil and Gas Journal (August 11, 2003) showed that the expense for managing drilling waste averages above 20 percent of the total cost of the drilling fluids, with wide regional variation (Figure 18). During 2002, as a result of more stringent regulations for offshore disposal of synthetic-based drilling fluids, the ratio of waste management to drilling fluid costs nearly doubled.

Land Access. Although the *AEO2004* projects adequate supplies of natural gas are available to replace reserves through 2018, it is difficult to determine the extent to which gas (and oil) resources can be economically recovered under increasingly restrictive controls concerning when and how companies can access Federal lands for exploration and production activities. Such controls are ostensibly designed to protect the environment from the potentially detrimental impacts of exploration and production activities. A significant amount of the Nation's natural oil and gas resource is located in federal waters or on federal lands not open for exploration or production. Policies for federal land access currently includes a moratorium on offshore drilling (Atlantic, Pacific, and Eastern Gulf of Mexico) and restricted drilling in the Rocky Mountains and in the Arctic National Wildlife Refuge.

The Energy Policy and Conservation Act (EPCA) Amendments of 2000 directed the Secretary of the Interior to conduct an inventory of oil and natural gas resources beneath Federal lands and to identify the extent and nature of any restrictions or impediments to the development of such resources. The first report in this inventory, focusing on five major geologic basins in the Rocky Mountains, determined that approximately 25 percent of the Federal land in those five basins is available for leasing with restrictions on oil and gas operations beyond standard stipulations, and based on USGS resource estimates, these lands contain 25 percent of the technically recoverable gas and 28 percent of the technically recoverable oil in these basins. Approximately 36 percent of the Federal land in the five basins is not available for leasing at all, and that portion contains about 12 percent of the technically recoverable natural gas and 15 percent of the technically recoverable oil. In total, 52 Tcf of technically recoverable natural gas resource and over 1.5 billion barrels of oil are contained under some degree of access restriction (Figure 19). In addition, a wide variety of operational and permitting hurdles can effectively restrict economic activity on areas where leasing is not actually restricted by lease terms.

Figure 19: Summary of EPCA Inventory Areas

			Area		Resources			
					Total Liquids*		Total Natural Gas**	
		Access Category	(acres x 1000)	Percent of Federal	(MMBbl)***	Percent of Federal	(Bcf)****	Percent of Federal
More Constrained	1.	No Leasing (Statutory/Executive Order)	10,068	16.9%	298	7.7%	9,035	6.5%
	2.	No Leasing (Administrative, Pending Land-Use Plan)	6,007	10.1%	116	3.0%	3,690	2.7%
	3.	No Leasing (Administrative)	5,098	8.6%	182	4.7%	3,185	2.3%
	4.	Leasing, No Surface Occupancy	2,714	4.6%	50	1.3%	3,120	2.3%
	5.	Leasing, Cumulative Timing Limitations on Drilling >9 Months	25	0.0%	3	0.1%	114	0.1%
	6.	Leasing, Cumulative Timing Limitations on Drilling 6-9 Months	2,521	4.2%	250	6.5%	5,549	4.0%
	7.	Leasing, Cumulative Timing Limitations on Drilling 3-6 Months	5,442	9.2%	528	13.7%	20,401	14.7%
	8.	Leasing, Cumulative Timing Limitations on Drilling <3 Months	697	1.2%	8	0.2%	733	0.5%
	9.	Leasing, Controlled Surface Use	3,753	6.3%	221	5.7%	6,080	4.4%
Less Constrained	10.	Leasing, Standard Lease Terms	23,091	38.9%	2,198	57.0%	86,566	62.5%
		Total, Federal Lands Including Split Estate	59,416	100.0%	3,854	100.0%	138,472	100.0%
		Total Non-Federal	44,256		2,455		87,668	
		Total Study Area	103,672		6,309		226,141	

* Comprising oil, natural gas liquids, and liquids associated with natural gas reservoirs.
** Comprising associated dissolved and nonassociated natural gas.
*** MMBbl: Millions of barrels.
**** Bcf: Billion cubic feet.

Long-Term Affordable Energy

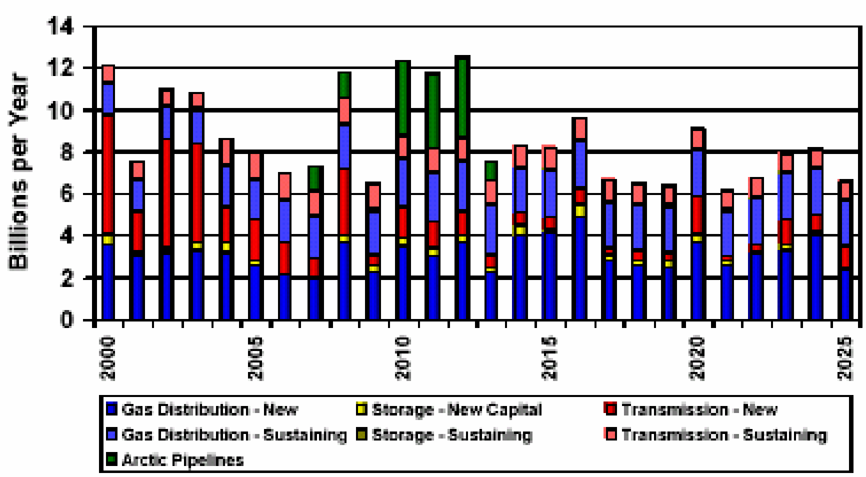
There are two key components to this driver: investments in oil and gas (including LNG) infrastructure, and R&D investments to support technology advances for exploration and production to provide long-term sustainable gas supplies.

Infrastructure Investment are Required to Meet Market Demands. The U.S. natural gas infrastructure, while robust and reliable, is facing operational challenges. According to the NPC (2003) an additional 20 million new residential customers will be added to the natural gas delivery system by 2025. This increased demand as well as expected increased demand from other sectors of the economy will require more than 40,000 miles of new gas transmission lines and almost 275,000 miles of distribution mains. NPC also estimates 700 Bcf of new storage capacity will be needed to satisfy annual gas demand.

Approximately 90 percent of the current transmission pipeline system is more than 20 years old. According to data from the Office of Pipeline Safety there have been 1,466 "incidents" reported since 1986. These incidents, which include natural disruptions (e.g., tornado), material failure (e.g., corrosion), and human error (e.g., excavation damage) have resulted in 60 fatalities, 232 injuries and property damage estimated at more than $350 million. Thus, in addition to future expansion requirements, significant capital and attention to maintenance of the existing transmission infrastructure will be needed over the next 25 years.

In 2002 Congress passed the Pipeline Safety Improvement Act (PSIA), which requires enhanced inspection and maintenance programs of all pipelines located in population centers. According to the Act's requirements, over 50% of the riskiest pipeline segments in these regions must be "physically" inspected in the next five years. The remaining facilities must be inspected during the following five years and all pipelines must be subsequently re-inspected at less than seven-year intervals. NPC estimates that the cost of expanding the transmission, distribution and storage system as well as maintaining the current system will cost more than $8 billion annually (Figure 20).

Figure 20: Annual costs to expand and maintain TD&S system (NPC 2003)



Without technology improvements to the overall energy delivery system, American's can expect more system failures, delivery system shutdowns, and interruptions in supply, and consequently an increase in their energy bills. The NEP concluded that recent natural gas system failures highlight the need to develop technologies and policies that protect people, the environment, and the safety of the nation's energy infrastructure. "The federal government has an important role in ensuring and improving the safety of the nation's energy infrastructure. New technologies need to be developed to improve monitoring and assessment of system integrity, improve data quality for system planning, extend the serviceability and life of the national natural gas transmission and distribution network, provide safer transport of energy products, and lessen the impacts of the energy infrastructures on the environment."

If LNG is to provide a growing share of the U.S. gas market demand, expansion of the four existing facilities and/or new import terminals will be required. The costs of building and operating receiving terminals are very site specific. In the United States, new terminals built on the design of those already in existence could be expected to cost between 200 and 300 million dollars.[4] The cost of constructing offshore LNG ports will be substantially more. For example, construction costs for Port Pelican (Figure 21), the ChevronTexaco offshore facility approved on November 17, 2003, are estimated at $800 million.[5]

Figure 21. ChevronTexaco's Port Pelican offshore receiving and revaporization facility 40 miles off the coast of Louisiana. *Construction of the freestanding concrete gravity based structure is expected to begin in 2004 with operations beginning in 2007.*

U.S. and worldwide investment in refineries will also be necessary to meet future demand. As previously mention, it is unlikely that new refineries will be built in the U.S. however, domestic companies will still have to invest millions of dollars in order to keep pace with changing feedstocks and increasingly stringent product specifications. Generally speaking, crude oil will become heavier and higher in sulfur and other

[4] GTI, as referenced in the The Global Liquefied Natural Gas Market: Status and Outlook by the Energy Information Administration DOE/EIA-0637 (2003), p. 46.

[5] Calvo, Daniel (Los Angeles Times), *A Sea Change for Natural Gas Imports*, Stanford University Center for Environmental Science and Policy, January 11, 2004.

impurities. At the same time, increased supplies of synthetic crude oil from sources such as Canada's oil sands bitumen and gas-to-liquid streams will enter the market. Refineries will be challenged to understand how these new feedstocks will affect overall operations and yields, and which conversion processes to invest capital.

On the product side, ultra-low sulfur transportation fuels are a major issue facing domestic and international refineries. New state limits on the use of MTBE because of concerns about groundwater contamination will also challenge refiners to find new ways to meet oxygenate requirements for reformulated gasoline. In the future, restrictions on aromatic content and toxics are possible. All of these challenges will strain U.S. refining capacity and require increased flexibility and capital investment.

Translating Reserves into Affordable Supplies. To meet the Nation's energy needs, industry continually explores and develops the remaining technically recoverable resource base. Attempts to identify and drill the most profitable prospects generally meet with mixed success (ranging from less than 10% in frontier regions to 80% in mature areas). Oil and gas that is discovered and can be profitably produced is added to reserves. These reserve additions must replace the continual depletion of reserves due to ongoing consumption (currently about 22 Tcf per year for gas). As a result of this process, if nothing else is done, the technically recoverable resource base will decrease, both in quality and quantity. To counter this effect, industry relies largely on: (1) shifting to less-explored areas (increasingly overseas) and (2) incremental technology advances to slowly expand and improve the economics of the remaining resource.

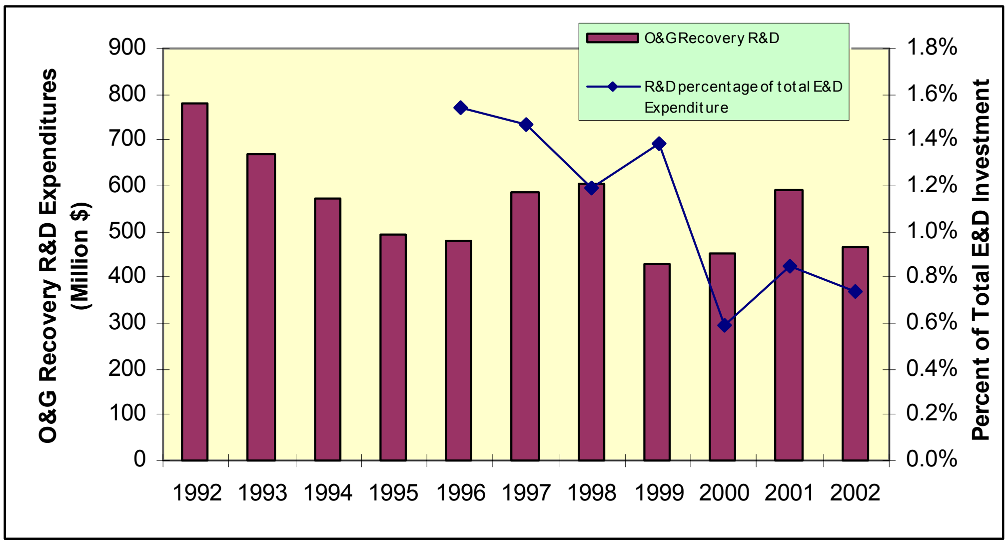
Significant resource expansion, however, often requires a collaborative government-industry effort of high-risk, high-return R&D to produce critical technology advances that unlock portions of a vast, untapped gas-in-place resource. Over the past three decades, such successes have delivered tight-gas sands, coalbed natural gas, the deepwater Gulf of Mexico, and gas shales into the Nation's resource base—effectively replenishing the technically recoverable resource base at a rate approximating its consumption. The success of the Canadian oil sands is another example of successful government-industry collaboration. Using the Canadian experience with existing technology and further technological advances, economic and environmentally acceptable U.S. shale oil production of comparable volume could result, reversing this nation's declining oil reserves trend. To begin development of a viable oil shale industry, issues of immediate concern include: land, water, and mineral rights, permitting, stimulation of capital formation and incentives for private sector investment—for R&D as well as commercial-scale operations.

In coming decades, continued resource expansion certainly will require new technology as new production will come from deeper wells, deeper water, and unconventional formations that are harder to reach and more difficult to produce. New technology will also be needed to enable or to reduce the cost of compliance with ever more stringent environmental regulations including a whole range of existing, new and potential regulations such as:

- Effluent guidelines for synthetic-based drilling fluids
- Underground injection of produced water
- Elimination of diesel fuel hydraulic fracturing fluids
- Reduction in green house gas emissions from motor fuels
- Implementation of the PSIA

Compliance with environmental regulations increases financial risk lowering the attractiveness of many potential oil and gas plays. Reduced profits also impact industry's decision to invest in R&D. Unfortunately, in the U.S. industry investment in R&D has steadily declined as industry implements cost-cutting measures, streamlines operations, and transfers investments to low-risk production overseas. These consolidations and cutbacks have led to a reduced investment in R&D. Figure 22 shows the R&D investment by major energy producers since 1992 and the percentage of R&D investment to total exploration and development expenditures since 1996.

Figure 22: R&D Expenditures by Major Oil Companies (EIA Performance Profiles of Major Energy Producers 2002 and historical Financial Reporting System, Form EIA-28 data)



If new sources of natural gas and oil are to be produced economically in this country, industry and government together need to develop advanced technology at a significant pace. However, advanced technologies will not contribute to meeting projected demand unless they are applied in the field. The government has a fundamental role through tax incentives, cost-shared demonstration, and other policy mechanisms to encourage industry to apply new technologies that assure national energy security. The government also has a vital role in setting policy and developing regulations that reduce environment harm, and contribute to a more robust economy while simultaneously providing the U.S. energy industry access to economical and technically recoverable resources on federal lands and currently prohibited offshore areas. In an ever expanding world market for oil and gas energy resource, sound energy policy not only helps Americans but also provides U.S. oil and gas companies with a competitive advantage internationally.